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Financing investments in renewable energy: the impacts of policy design

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Abstract

The costs of electric power projects utilizing renewable energy technologies (RETs) are highly sensitive to financing terms. Consequently, as the electricity industry is restructured and new renewables policies are created, it is important for policymakers to consider the impacts of renewables policy design on RET financing. This paper reviews the power plant financing process for renewable energy projects, estimates the impact of financing terms on levelized energy costs, and provides insights to policymakers on the important nexus between renewables policy design and financing. We review five case studies of renewable energy policies, and find that one of the key reasons that RET policies are not more effective is that project development and financing processes are frequently ignored or misunderstood when designing and implementing renewable energy policies. The case studies specifically show that policies that do not provide long-term stability or that have negative secondary impacts on investment decisions will increase financing costs, sometimes dramatically reducing the effectiveness of the program. Within U.S. electricity restructuring proceedings, new renewable energy policies are being created, and restructuring itself is changing the way RETs are financed. As these new policies are created and implemented, it is essential that policymakers acknowledge the financing difficulties faced by renewables developers and pay special attention to the impacts of renewables policy design on financing. As shown in this paper, a renewables policy that is carefully designed can reduce renewable energy costs dramatically by providing revenue certainty that will, in turn, reduce financing risk premiums. © 1998 Elsevier Science Ltd. All rights reserved.

1. Introduction

As part of the international trend toward electricity industry restructuring, a number of countries and several U.S. states are establishing new forms of public policy

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support for renewable energy. Depending on their design, policies to encourage the development and use of renewables, such as solar, wind, biomass, and geothermal, can have positive or negative impacts on project financing costs. This paper reviews the financing process for renewable energy projects and identifies important relationships between policy design and finance. We emphasize five policy case studies, each of which provides critical lessons for the design of future renewable energy support programs. The paper combines qualitative assessments of the interactions between policy design and power plant financing with quantitative analysis of some of these interactions.

Although the cost of renewable energy has fallen dramatically over the past 20 years and some renewable energy projects are now economic on a private-cost basis, renewables are frequently more costly than other forms of electricity generation [1]. Renewables provide social benefits that are not fully internalized in investment decisions, however, including pollution reduction and the mitigation of electricity price variability [2, 3]. To overcome this market failure and reduce institutional barriers, policies have been enacted in the U.S. and abroad to encourage renewable energy technology and project development. These policies have included tax incentives, cash payments, renewables set-asides, standardized power sales contracts, and low-interest loans.

Yet past experience with these and other renewable energy commercialization policies has been mixed, and renewables still make up only a small fraction of worldwide electricity production. Ideally, policy design should link incentive mechanisms to policy goals, subject to technical, market, and financial constraints. This criterion is not always met, however, and political considerations and/or lack of information often impact policy development, frequently resulting in mismatches between a policy's incentive mechanism and technical, market, or financial constraints [4]. Because of this dynamic, a number of renewables policies have not been as cost-effective as they could have been if they were designed differently.

Depending on their design, programs to support renewables can have positive or negative impacts on project financing and financing costs. This paper emphasizes power plant financing as an integral consideration in the design of cost-effective renewable energy policies. We argue that one key reason that renewables policies have not been more effective is that project development and financing processes are frequently ignored or misunderstood when designing and implementing support programs. As discussed in section 2.3, financing is particularly important for renewables developers because their projects are often disadvantaged in the financing process relative to other sources of electricity generation [5–7].

By increasing project risks and decreasing the availability of long-term power sales contracts, electric industry restructuring may further handicap renewables in the financing process. But restructuring has also brought renewed attention to renewable energy policies. Existing forms of public support, many of which have been funded and administered by regulated electric utilities, will not all be appropriate in a restructured electric industry [8]. New approaches for supporting renewables are being sought [9–11] and, given the likelihood that new policies will emerge out of the restructuring process, it is important for policymakers to understand the problems that can arise if

policies are not designed with consideration given to financing. Moreover, at a time when the emphasis appears to be on shorter and more market-driven renewable energy policies than those used in the past, reviewing and highlighting the financing implications of policy design is all the more essential. Armed with a better understanding of the relationships between policy design and financing and with concrete lessons from past policies, policymakers should be better prepared to design and implement new renewable energy programs within electricity restructuring efforts.

We begin this paper by providing a background to the financing process for power projects generally, and renewable energy specifically. A cash-flow model is used to briefly illustrate the effects of key financing variables on renewable energy project costs. Next, we review a series of five case studies to demonstrate that many renewables policies have not fulfilled expectations, due, in large part, to their impacts on financing. The case studies highlight important relationships and lessons that must be understood in order to improve and refine prospective renewables policies. The paper concludes by discussing some of the specific ways that restructuring will impact the financing of renewable energy projects, and by briefly reviewing new renewables policies in light of our case study findings.

2. Renewable energy financing and project development

In this section we provide much of the background required to understand the financing of renewable energy projects. In 2.1, we introduce the power plant development process. Then, in 2.2, we discuss some of the key concepts, terms, and variables used in power plant financing. Finally, in 2.3 we identify the most common financing arrangements used in the renewables industries to date and describe the financing barriers facing renewables compared to more traditional generation alternatives. We illustrate the effects of key financing variables on renewable energy project costs using a simple cash-flow model.

2.1. *Project development*

It is important to understand the overall process of project development before specifically addressing renewable energy finance. While we cannot specify a project development process that is applicable to all types of power projects and to all business situations, almost all non-utility generator (NUG) projects that use project financing must pass through similar development stages, as shown in Fig. 1.

Final financial approvals (closing) is one of the later stages of project development prior to construction and operation. Although financial institutions are frequently approached earlier in order to scope-out financing costs for the contracting stage and determine investor interest in the project, final financial approvals (especially loan agreements) are typically obtained only after all significant engineering, contracting, and permitting requirements are met [12].

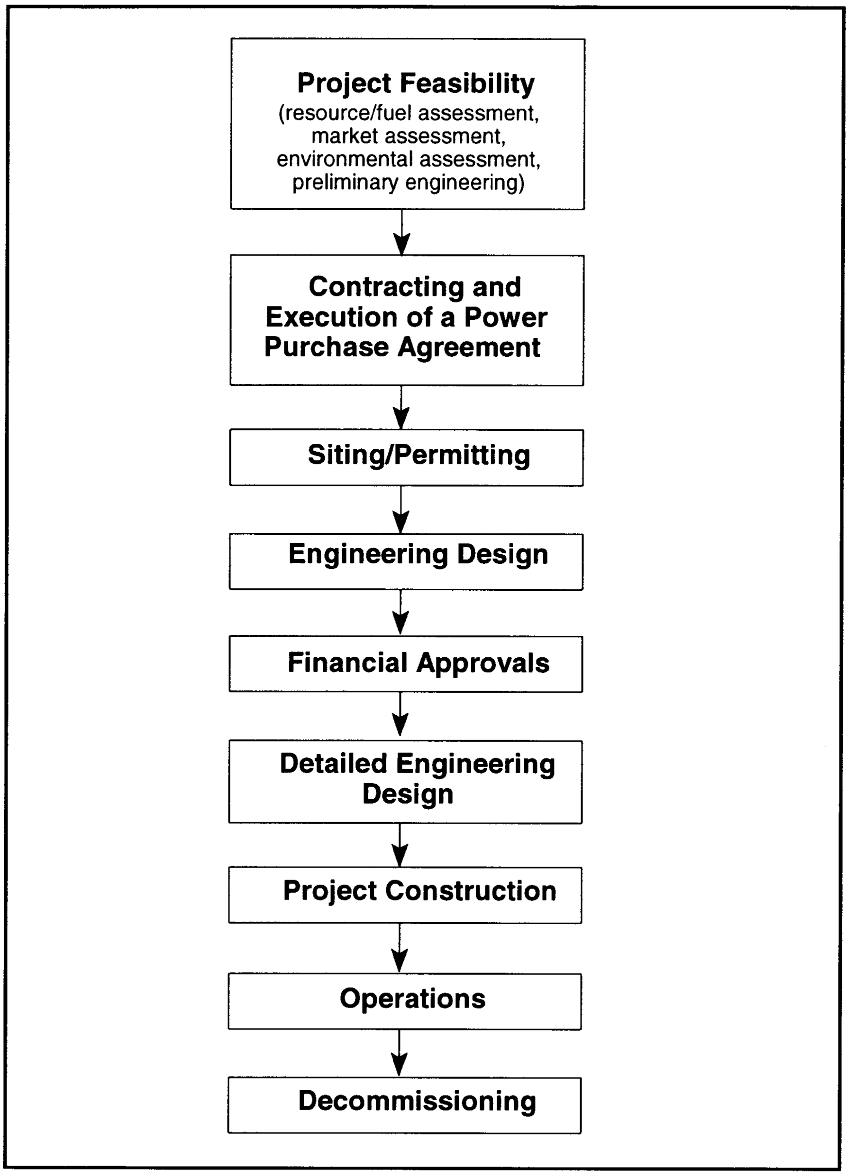

Fig. 1. Conceptual stages of project development.

2.2. *Financing a power project*

2.2.1. *Sources of capital*

Project developers typically obtain capital for the up-front cost of building a power project through a combination of debt (a loan) and equity investment (ownership).

There are a large number of ways to structure loan agreements, and debt can be obtained through public markets (bonds) or private placements (bank loans and institutional debt). Equity can be procured from internal sources or external investors in public or private markets.

Equity investors and lenders view and analyze projects (and firms) very differently. Equity investors have the potential for unbounded returns from project (or firm) success. Equity investors will therefore frequently take high-risk investments if the potential rewards are large. Investments are analyzed from a risk-return tradeoff with an emphasis on the expected investment return.

Most lenders, on the other hand, tend to be far more risk averse. The debt contract is a fixed obligation and the lender does not profit, beyond a certain level, from project (or firm) success. Up to the limit of unacceptable risk, lenders adjust debt interest rates and terms for default risk (i.e. higher interest rates on riskier loans). As a result of credit rationing, however, lenders will simply not take some risks. If a project (or firm) is likely to default or come close to default in any single year, lenders will often not supply a loan. Therefore, unlike equity investors, lenders typically analyze a project (or firm) from a worst-case perspective [13].

2.2.2. *Project and corporate financing*

There are two primary ways to finance a power plant: project financing and corporate financing. These two financing structures differ primarily in how debt is structured.

(1) Project financing: Non-utility generators have generally relied on project financing. In these arrangements, lenders look primarily to the cash flow and assets of a specific project for repayment rather than to the assets or credit of the promoter of the facility. The strength of the underlying contractual relationships among various parties is essential in project financing. Credit support (i.e. support for a loan) in project financing comes in large part from the revenues associated with the power purchase agreement (PPA). Therefore, long-term power purchase commitments that, at least partially, guarantee a revenue stream are essential, especially for high capital-cost technologies such as renewables. An unpredictable or unspecified revenue stream is a risk that most project financing lenders are unwilling to take. Another important general rule of finance is that debt is frequently less costly than equity [14]. As such, with project financing, there is a tendency for developers to maximize debt leverage (i.e. the percent of debt used to finance a project). This tendency is limited, in part, by debt service coverage requirements, described in more detail later.

(2) Corporate financing: When corporations borrow money from either public or private markets, lenders look to the entire corporate balance sheet for repayment. Corporate financing (often called internal or balance-sheet financing) therefore lacks the degree of asset-specificity found in project financing. The primary requirement made by lenders in corporate financing is a restriction on the issuing of debt beyond certain limits [15]. Additional debt can hurt bondholders and other lenders because it reduces the ability of a firm to pay interest on existing debt. The use of corporate financing to supply the capital needs of individual

power projects is common in the electric utility industry and, as discussed further in Section 4, is expected to become much more frequent in the independent power market as electricity restructuring takes hold.

Project financing has several advantages over corporate financing. Loans are generally non-recourse (sometimes limited-recourse) to the parent company and therefore do not have a substantial impact on the company's balance sheet or creditworthiness. As a result, small- and medium-sized developers are free to pursue several projects simultaneously without large negative company-wide impacts. In addition, the reduced market risks and non-recourse nature of debt in project financing allows higher debt-equity ratios, which can result in reduced financing costs. Nevitt [16] and Brown [17] identify a number of negative aspects of project financing compared to corporate financing, including the need for strong purchase commitments, the large transactions costs of arranging the various contracts, high legal fees, higher debt costs, and a greater array of restrictive loan covenants.

2.2.3. *Key financing variables*

There are a number of specific financing variables that will be discussed and used in the remainder of this paper. Table 1 provides a review and summary of these key financing variables.

2.3. *Developing and financing renewable energy projects*

2.3.1. *Ownership and financing arrangements for renewables*

Most large-scale, non-hydroelectric renewable energy projects in the U.S. have been developed, owned, and financed by non-utility generators. Although not as common, utility ownership and financing of non-hydroelectric renewables projects has also occurred. Utility ownership has been primarily limited to geothermal facilities, although some utility-owned biomass, photovoltaics (PV), and wind projects exist and others are in the development stage. Among the renewable energy technologies, differences in financing and ownership, as well as sources of debt and equity, exist. Table 2 reviews the financing arrangements that have become common within each of the renewables industries.

2.3.2. *Historic financing barriers for RETs*

Financing variables are particularly important to RETs because renewables are often capital intensive, and therefore require a greater degree of up-front debt and equity than power plants with lower capital costs. In addition, a number of factors make it more difficult for renewables to obtain financing at reasonable costs than for more mainstream generation technologies (e.g. gas or coal):

(1) Project risks: Many RETs are perceived by the financial community to have high resource and technology risks [18, 19]. Most financial institutions do not have significant experience in evaluating renewable energy resource risks (wind variability and biomass availability, for example). Many RETs are also perceived as unproven, with large performance risks. Institutional memory of past project

Table 1
Summary of financing variables

Term	Description
Capital Structure	Capital structure refers to the mix of debt and equity that is used to finance a project or a firm. Debt-equity ratios are frequently used to describe the capital structure of a particular facility.
Return on Equity (ROE)	In exchange for their up-front capital outlay, equity investors require a minimum expected return on their investment, typically expressed as a yearly percent ROE. Equity represents a residual claim on all surpluses generated by the project. Equity returns can come in the form of direct project cash flows and/or as tax shields (tax credits and accelerated depreciation).
Debt Maturity	Debt maturity, or debt term, refers to the length of a loan.
Debt Interest Rate	All lenders charge interest. The interest rate will typically depend on the maturity of the loan and its risk.
Debt Amortization	Debt payments consist of principal and interest. Debt amortization refers to the debt payment schedule. In project financing, debt principal payments are typically made throughout the life of the loan, often with mortgage-style repayment.
Debt Service Coverage Ratio (DSCR)	To reduce default risk, lenders typically require that a project or firm maintain a minimum expected ratio of the available cash to total yearly debt service. This constraint is usually expressed as a minimum acceptable value for the DSCR (yearly operating income/total debt service).

failures makes raising capital difficult and costly for many renewables developers [20]. These real and perceived risks generally result in financing that is more costly than that available to more traditional generation sources. Wiser and Kahn [21], for example, estimate that if wind developers received similar financing terms and costs as gas-fired NUGs, the nominal levelized cost of wind power might decrease by 25%.

(2) Industry Size and Investor Interest: The U.S. renewable energy industry is still relatively small, and many investors do not feel that the work necessary to follow technology and performance trends is worth the effort [22]. The shortage of independent RET experts compounds the problem [23]. Investors are typically reluctant to invest in technologies that have not been followed closely.

(3) Not only is the U.S. renewable energy industry as a whole relatively small, but most renewable energy projects are also small compared to coal, nuclear, and natural gas facilities. Many financing institutions are not interested in small transactions [24]. Even if financing is available, the transaction costs per megawatt are much higher for smaller projects because many of the same financing and development steps must be followed regardless of facility size [25, 26].

Table 2
Technology-specific financing arrangements and sources of capital

Technology	Financing arrangements and sources of capital
Biomass	The wood-fueled biomass industry consists of a wide variety of organizations, and includes small and large private and public companies. Prior to the 1980s, wood-fueled biomass projects were financed predominately with balance-sheet, corporate financing by companies in the paper and timber industries interested in wood-waste reduction, steam production, and electricity sales. During the mid-1980s through the present, the wood-fueled biomass industry has used NUG project financing extensively to develop PURPA-based projects. These projects have frequently been highly leveraged. Equity has generally been obtained from internal sources (i.e. the developer and/or its parent corporation) and debt has been received from commercial banks, institutional investors, and through tax-exempt bonds. The landfill gas and municipal solid-waste industries have relied on a number of different financing and development structures (often in partnership with local governments), including project financing.
Geothermal	The geothermal industry contains private and public companies. Before the mid-1980s, the industry was dominated by large petroleum companies and a few smaller steam-field development companies. Both of these types of companies frequently developed the geothermal field and sold the steam to public utilities, which were the primary owners/operators of the geothermal power plants. These early companies generally used corporate financing arrangements and joint ventures to finance projects. Most developers are now medium-sized firms and most oil companies have ended their geothermal activities (except Union Oil). Since the implementation of PURPA in the early 1980s, NUGs have built, owned, and operated geothermal projects; these developers typically use project financing.
Solar	The photovoltaic industry includes small private companies and wholly owned subsidiaries of large public corporations. Until recently, the PV industry has been dominated by manufacturers selling directly to customer markets and/or utilities. Utility PV owners generally use corporate financing while electricity end users can finance projects through internal funds, bank loans, or mortgage payments. Although PV manufacturers have used internal equity to finance project capital needs in a limited number of circumstances, NUG development and ownership is only beginning to play a more substantive role in this market. Project financing arrangements have not yet taken place, but the Amoco/Enron partnership and other developments may possibly result in an increasing number of these financial structures. The solar thermal industry, under Luz International Limited (LUZ), developed projects in the mid- to late 1980s through third-party project financing arrangements. Equity sources included utility subsidiaries and institutional investors.
Wind	The wind industry consists of private and public companies. During the early 1980s, almost all wind power development occurred through tax-advantaged limited partnerships of third-party individual investors. Sale/leaseback structures were popular in the mid- to late 1980s, but more traditional non-recourse project financing with independent debt and equity investors has now become the dominant form of wind power development. More recently, a number of utilities have expressed interest in owning wind plants.

(4) Unpredictable Policies: The economics of many renewable energy projects relies heavily on government policies (tax credits, set asides, etc.). As will be covered in detail shortly, these policies have often been unpredictable and subject to manipulation. To the extent that unpredictability in these policies provides some uncertainty to the underlying economics of RETs, financiers will be reluctant to invest.

2.3.3. *Impact of financing on project costs*

To illustrate the importance of certain key financing variables on renewable energy project costs, a financial cash-flow model was created. Though the model itself simplifies the financing process in several respects, and the detailed results of our analysis are not presented here, the model closely replicates the types of financial models used in the private power industry. The model tracks revenues, expenses, debt payments, and taxes over a 20-year period and estimates an after-tax, net equity cash flow. With minor modifications, the spreadsheet model can be used for all types of power supply projects. Models of this form are typically used by NUGs to compute bid prices and determine project profitability, and by financial institutions in project evaluation. Using a constrained optimization algorithm, the model calculates the 20-year levelized power purchase price (and therefore the power purchase cost) required to meet all cost and financial constraints. Subject to the minimum return on equity and debt service coverage requirements, the levelized cost is minimized by optimizing the debt-equity ratio. The two model outputs are, therefore, the optimal capital structure (i.e. debt-equity ratio) and the levelized cost of energy. We emphasize the latter output in this section and report all costs on a nominal 20-year levelized cost basis in 1998 dollars. For a more detailed description of the model, its inputs, and its development, applied to a wind power facility, see Wiser and Kahn [27].

We evaluate cost sensitivities for a representative 50 MW wind power facility and a hypothetical 5 MW grid-connected photovoltaic installation[1]. We assume that both facilities are developed by NUGs with project financing under long-term power sales contracts. Our base-case financing assumptions include: 18% equity return, 12 year debt maturity, 9.5% debt interest rate, and a capital structure that is optimized to minimize overall levelized cost. These financing assumptions, as well as our project cost inputs (not listed here), are generally consistent with other sources [28–36].

Using these assumptions, the nominal levelized cost of the PV facility is calculated to be 26.3 ¢/kWh; the levelized cost of wind power is 5.5 ¢/kWh. Table 3 demonstrates the sensitivity of PV and wind power costs to various financing inputs. For each sensitivity case, an individual financing term was varied while other inputs were held constant (thereby ignoring the interactive effects of some of these variables). While the sensitivity results are not evaluated in detail in this paper (see Wiser and Pickle

[1] We model a large-scale PV facility for illustrative purposes only. Grid-connected PV facilities of this size are not currently economic unless substantial ancillary benefits are obtained through transmission and distribution cost reductions, reliability increases, etc. In the medium- to longer-term, these facilities may prove economic as PV costs decrease and the value of PVs in niche markets is realized.

Table 3
Project cost sensitivity analysis

Financing sensitivity	PV levelized cost (¢/kWh)	Wind levelized cost (¢/kWh)
Base-case[a]	26.3	5.5
12% equity return	21.7	4.3
24% equity return	29.6	6.5
13% debt interest rate	29.3	6.0
5% debt interest rate	22.5	4.9
20-year debt	21.9	4.8
8-year debt	30.4	6.2

[a]18% equity return, 12 year debt, 9.5% interest rate.

[37]), the results confirm that the return on equity, debt interest rate, and debt maturity all have a significant influence on overall costs. Even relatively small changes in these variables are shown to impact overall levelized project costs by 20% or more. The significance of these variables will be further illustrated below in our review of key renewable energy policy case studies.

3. Policy case studies

Many government programs have been successful in promoting renewable energy. A number of policies have had unintended negative impacts on financing costs, however, reducing overall program effectiveness. In this section, we highlight the importance of policy design for renewable energy financing by reviewing five case-studies of current and past renewable energy programs. Each of the cases shows how specific policy design variables can negatively impact financing, and each therefore provides discrete lessons for the design of future support programs. A brief summary of the case-study lessons is given in Table 4.

3.1. *Tax policies and tax appetite*

Tax incentives have played a prominent role in renewable energy policy and have included accelerated depreciation, investment tax credits, production tax credits, and property and sales tax reductions or exemptions [38–40]. The primary justifications for these policies have been : (1) to promote diversity in energy supply, and (2) to offset other tax-related barriers to renewables and promote tax ‘equity’ across electricity generating alternatives [41, 42].

Not all renewable energy tax policies have proven effective, however. In 1978, the U.S. Congress enacted several tax incentives to stimulate the commercialization of RETs. By 1982, most renewable energy projects were eligible for a 10% business investment tax credit, a 15% business energy investment tax credit, and five year accelerated depreciation. Additional investment tax credits were available at the state

Table 4
An overview of the case study lessons

Case study	Lessons
Tax policies and tax appetite	The effectiveness of tax incentive policies is reduced by limitations on the tax appetite of investors and by the alternative minimum tax (AMT). Partial AMT relief for RET projects should be considered. The use of direct cash subsidies rather than tax incentives would largely eliminate tax appetite limitations, as would the ability to 'sell' tax credits directly to other investors.
Policy uncertainty and the demise of LUZ	The importance of policy stability to renewable energy developers and financial investors should not be underestimated. To the extent possible, RET policies should be stable so that equity investors and lenders are encouraged to supply capital to RETs at reasonable costs.
Effect of the production tax credit on capital structure	Production tax credits can push the optimal mix of debt and equity in the capital structure of RET projects toward higher-cost equity, therefore reducing the value of the credit moderately.
The renewable energy production incentive and program funding uncertainty	If cash production incentives are used for renewables support, it is important to provide enough certainty in program funding so that the payments can be used as debt security and can substantively affect investment decisions.
The U.K.'s non-fossil fuel obligation and contract length	Contract duration and contract sanctity have important impacts on financing. RET policies that provide contracts or incentive payments to renewable energy projects should be designed as long-term commitments. Short periods and 'out' clauses should be minimized.

level. As noted by Cox et al. [43] and Walton and Hall [44], one of the major lessons learned from these early investment tax credit (ITC) policies was that support should be tied to project performance, not just capital investment. In some states, notably California, capital-based tax incentives resulted in large renewable energy capacity additions in the early 1980s, but provided project owners limited incentives to maximize electricity production. In part as a response to this criticism, the 1986 Tax Reform Act reduced the federal tax incentives available to renewables projects and many of the state tax incentives have been eliminated over time. In 1992, however, the Energy Policy Act created a 10-year 1.5 ¢/kWh production for wind and closed-loop biomass and permanently extended the 10% business energy ITC for non-utility investors in solar and geothermal facilities.

Even where ITC failings have been corrected, state and federal tax policies can still have other undesirable secondary impacts. Three specific financing-related issues have been raised by tax incentive policies, all of which have reduced the effectiveness of these programs, including: (1) the alternative minimum tax and limitations on the tax 'appetite' of investors; (2) the effect of policy instability on developers and financiers; and (3) the secondary impacts of production tax credits on the capital

structure of renewable energy projects. This section discusses the first of these issues, whereas the other two are examined later.

Accelerated depreciation and income tax credits can give significant tax benefits to equity investors in renewable energy projects. However, not all equity investors have sufficient income, and therefore tax loads (referred to as tax 'appetite'), to absorb the full value of these tax benefits. The ability of investors to: (1) use the renewable energy tax benefits to offset other (non-renewables project) tax loads; (2) carry forward or carry back tax benefits to other years to offset income tax liabilities; and (3) allocate the tax benefits among investors regardless of ownership share, can all help alleviate the tax appetite problem. Many of these steps have already been integrated into the federal tax code.

Alternative minimum tax (AMT) requirements often exacerbate problems associated with tax appetite, however, and therefore reduce the value of tax incentives to renewable energy investors. In the Tax Reform Act of 1986, the U.S. Congress enacted the present AMT to ensure that the benefits of tax preferences are limited and to guarantee that taxpayers pay a minimum level of taxes. The AMT is computed with a modified depreciation schedule that is less favorable than the five-year system allowed for normal tax purposes, and most tax credits cannot be credited against the AMT. Under the AMT, once taxable income is adjusted by the alternative depreciation schedule, a lower tax rate of 20% is applied. If income taxes are higher using the AMT than in the normal calculation, the entity must pay the AMT amount. The AMT can therefore postpone the use of tax credits and favorable depreciation. Because of the time value of money, the value of these tax benefits decreases the longer they are carried forward. If a company is perpetually AMT limited, tax credits and accelerated depreciation may never be used.

Because renewable energy developers are often smaller companies in capital-intensive industries and have high depreciation allowances and tax credit benefits, they are frequently subject to the AMT [45]. Even without the AMT, some of these companies may not generate enough taxable income to fully utilize tax benefits without significant carry-forwards. Hill and Hadley [46] find that the AMT can have an enormously negative impact on the internal rate of return for renewable energy projects, but has minimal impacts on returns for conventional technology. Using a simplified cash-flow analysis, they estimate that the AMT alone can reduce the overall internal rate of return for a PV project by 29%, 23% for biomass, 25% for geothermal and 35% for wind power. The reduction for conventional generation sources was found to be, at most, 6%.

When subject to the AMT constraint, renewable energy developers often seek to obtain outside equity investors who are not limited by the AMT and who have sufficient taxable income to absorb the full value of the tax incentives. Not all renewable energy developers have a sufficient track record to easily attract outside investors, however. In addition, lenders and third-party investors frequently require developers to contribute some portion of a project's equity to maintain performance incentives and demonstrate a long-term financial commitment to the project. Even if a developer can access outside investors, the AMT limits the number of investors interested in renewable energy facilities. Lotker [47] contends that many of the large

investors that might otherwise have been interested in investing in Luz International Limited's (LUZ) solar-thermal trough systems were in an AMT-limited situation, reducing the investor pool. The net effect of the AMT is therefore to dampen demand for investment in renewable energy projects, creating a need for higher yields to attract investors.

Given the impact of the AMT on the value of tax incentive policies, pursuing partial AMT relief has been a priority for the renewable energy industries. The American Wind Energy Association, for example, has suggested loosening the AMT for wind and allowing the PTC to offset up to 25% of a taxpayer's AMT [48]. In addition, the development of 'assignable' tax credits (tax credits that could be sold directly to an unrelated party with tax liability sufficient to absorb the full value of the credit) could increase the effectiveness of tax credit policies from the developers' perspective. The AMT experience also suggests that, where tax appetite limitations are evident, legislators may want to consider using direct cash subsidies rather than tax incentives to support renewables. Overall, this case demonstrates that, when assessing the potential value of a renewable energy policy, special attention must be paid to the possible secondary impacts of the policy on investors.

3.2. *Policy uncertainty and the demise of LUZ*

Changes in renewable energy subsidies have tended to be abrupt and therefore disruptive to developers and investors. In some cases, this has made it more difficult to attract investors and has increased financing costs. This section illustrates the problems associated with policy instability by describing a specific case, that of Luz International Limited.

Although many U.S. federal tax incentives were phased out in 1986, Congress included the 15% business energy ITC within a group of other tax credit policies called 'extenders'. These credits had to be renewed annually by the U.S. Congress. Consequently, though the incentive was not eliminated, its existence could not be guaranteed beyond a given year. This uncertainty was magnified in California, which provided a 25% ITC that was available only if the federal ITC was also in place.

Until 1991, when it was forced to file for bankruptcy, LUZ was the most successful developer of solar-thermal power plants in the world. Financed by outside investors, but designed and constructed by LUZ, nine solar-thermal plants totalling 354 MW were developed in California between 1984 and 1991. Though there are a number of reasons for the ultimate business failure of LUZ, the year-to-year uncertainties surrounding the renewal of both state and federal tax incentives led to a loss of confidence among potential investors and has been cited as a key factor in the company's demise [49].

To be certain of receiving the federal and state ITCs, investors in LUZ's plants wanted assurances that projects would be complete before the end of each year. Consequently, planning and construction of the plants became severely constrained. Each year, LUZ was forced to lobby Congress to pass an extension of the federal tax credit, get site approval from the California Energy Commission, raise capital from investors, and finally build the plant before December 31 when the ITC was set to

expire [50]. LUZ was ultimately forced to guarantee its investors that they would receive the ITC. This guarantee had to be secured by a letter of credit from LUZ that was, itself, backed by cash or other security. Under this arrangement, a significant portion of LUZ's revenues were tied up in the letters of credit, and any delay in project completion beyond December 31 would result in substantial losses for the company. Investors realized that a failure to meet the deadline could significantly affect LUZ's ability to pay off the letters of credit, and a higher risk premium was required. In addition, vendors and construction lenders charged large risk premiums on both goods and loans because of the high risks involved [51].

In 1989, the federal ITC was only extended for nine months, and a corresponding seven-month rushed construction period resulted in a roughly $30 million cost overrun [52]. Meanwhile, an error by California's financial office showed that LUZ's property tax exemption would cost the state $60 million. Based on that assessment, the governor vetoed the property tax exemption bill for solar properties. Faced with increased risk, a number of LUZ's investors backed out, citing political and economic uncertainty. While the financial office's error was eventually found and the governor did sign the property tax exemption bill, it was already too late for LUZ, which decided to file for bankruptcy.

The LUZ experience demonstrates the impact of policy uncertainty on finding and retaining investors. Many renewable energy developers continue to rely on state and federal policies, including tax incentives, and projects can take one to more than five years to develop, permit, and construct. Therefore, developers must absorb significant risk during the development of a project unless they are ensured that a particular policy will apply to their project when it comes on-line. Even where policies survive attempts at legislative intervention, agency and/or court rulings can significantly alter a policy's applicability and implementation.

Though it is impossible to design state or federal policies that eliminate all risk of policy instability, year-to-year uncertainty can increase financing costs dramatically and reduce the efficacy of these policies. Long-term and predictable policy commitments can, on the other hand, contribute to reduced financing costs and can help create a business climate that is conducive for investment. Wherever possible, policymakers should therefore seek to increase program stability. In particular, policymakers may want to consider 'grandfathering' provisions in renewables policies. Such provisions would allow projects to prove eligibility and would pledge policy support some time before a project begins construction and operation. Renewable energy companies could then develop their projects with reduced policy uncertainty.

3.3. *Effect of the PTC on capital structure*

The U.S. federal government currently provides a 10-year, 1.5 ¢/kWh PTC to qualified wind power and closed-loop biomass facilities. Although this incentive has stimulated wind power development, it inadvertently raises financing costs because of its impact on the capital structure (i.e. the mix of debt and equity used to finance projects) of renewable energy projects. This secondary impact has reduced the PTC's value by nearly a third.

To assess the value of the production tax credit, the wind power cash-flow model described earlier was run with and without the PTC. In addition to the levelized cost, the 'optimal' capital structure (i.e. the capital structure that minimizes levelized project costs) is also reported. The model assumes that investors have sufficient tax loads to absorb the full value of the tax credit.

As shown in Table 5, the PTC is estimated to reduce wind power costs by approximately 1.7 ¢/kWh (7.2–5.5 ¢/kWh). This cost reduction is greater than the quoted tax credit size of 1.5 ¢/kWh for two reasons. First, the PTC escalates with inflation; second, tax credits provide secondary benefits by reducing project tax loads. Specifically, the tax credit allows developers to reduce their power sales price, therefore decreasing operating revenues and reducing taxes even more than the direct value of the tax credit [53].

Table 5 also indicates that inclusion of the PTC leads to a greater proportion of equity in the project's capital structure. This is because the benefits of a tax credit appear only on the tax returns of equity investors; tax credits are useless for servicing debt and meeting minimum debt service requirements. Although the PTC allows a reduction in the wind power sales price, if capital structure is unchanged a decrease in the energy price results in a violation of minimum debt service coverage requirements (i.e. operating income may not be sufficiently high to service the full debt payments). To combat this problem, the project developer must increase the fraction of equity in the capital structure. Because debt is generally less costly than equity, a higher equity fraction increases the contract price from what it would be under an equivalently-sized, tax-exempt *cash* payment, which could be used to service debt. Table 5 shows that the value of such a cash payment is 2.7 ¢/kWh (7.2–4.5 ¢/kWh), implying that the capital structure impacts of the PTC reduce its value to a project developer by approximately 35% (from 2.7 ¢/kWh to 1.7 ¢/kWh).

Kahn [54] finds that bankability of the PTC (i.e. the ability to 'sell' the PTC for cash) would result in an incremental debt fraction of 20% (e.g. an increase in debt leverage from 50% to 70%) and that the penalty associated with a PTC compared to a tax-exempt cash incentive is an increase in financing cost of approximately 10%. These results are generally consistent with the cash-flow analysis presented here. As such, legislators should consider establishing bankable or 'assignable' tax credits, or as noted earlier, using direct cash production incentives rather than tax credit policies. Again, in order to maximize the effectiveness of any given renewable energy policy, this

Table 5
Impact of the PTC on the levelized cost of wind power

Scenario	Levelized cost (¢/kWh)	Capital structure (% equity)
Without PTC	7.2	39%
With PTC	5.5	59%
With equivalent cash payment	4.5	40%

case clearly illustrates the need for policymakers to carefully consider the secondary impacts of the policy on project financing.

3.4. *REPI and program funding uncertainty*

The renewable energy production incentive (REPI), created by the 1992 U.S. Energy Policy Act, provides a 1.5 ¢/kWh cash payment to non-profit owners of renewable projects (government-owned facilities or non-profit electric utilities). The REPI was created as the non-profit analogue to the PTC and ITC programs because tax credits cannot be used by tax-exempt entities. The incentive payment is available for 10 years, starting when the project begins operation.

Although the REPI was created to stimulate incremental renewable energy development, in its current incarnation it can only be considered a limited success. Funding for the REPI program is subject to yearly congressional appropriation. Moreover, the Energy Policy Act only authorized appropriations for 1993–1995; Congress must periodically renew the authority for these appropriations [55]. Because of the uncertainty associated with the funding for the REPI payments, non-profit renewables owners have no assurance that they will receive the payment throughout the 10-year eligibility period. In fact, beginning in 1996 congressional appropriations for the program have not been sufficient to meet the claims of eligible projects. The REPI therefore cannot be used as security for debt repayment.

To determine the value of the REPI to project owners, we informally surveyed representatives from each of the REPI recipients in 1995 (seven owners representing eleven projects). Project owners were asked whether the REPI's existence affected their decision to proceed with their renewable project(s). Realizing that some of these projects were in the development stage when the program was created (and, therefore, that the REPI had not been considered in project decisions), we also asked whether the payments would be considered in the evaluation of future projects. To quantify the results, each respondent was asked to express their evaluation on a scale from one to four. A '1' indicates that the existence of the REPI did not (would not) affect project decisions; a '4' signifies that the project would (will) not have moved forward without the program. Table 6 shows the results of the survey.

While all respondents appreciated the existence of the program, the survey results suggest that the REPI is not an effective incentive. Although the expected value of the payments is not zero, nearly all recipients that were interviewed did not and would not rely heavily on the REPI in project cost estimation and investment decisions. The REPI serves as a post-development bonus for those projects that manage to secure financing on their own, but it does not appear to generate a significant amount of development that would not otherwise occur.

The U.S. Department of Energy (DOE) is aware of these shortcomings and has taken steps to partially reduce the uncertainty in the payments. Though the U.S. DOE cannot guarantee an incentive payment because of program funding uncertainties, the DOE will provide a preliminary and conditional determination of eligibility for the REPI payments, therefore reducing the risk of a project being deemed ineligible for funds after-the-fact. In addition, though most renewable energy technologies are

Table 6
Impact of the REPI on project decisions: survey results

		Limited effect on project decisions **1**	**2**	← — — — — — → **3**	Strongly affects project decisions **4**
Impact of REPI on existing projects	Utilities	4	2	0	1
	% 1995 REPI REPI Funds	83%	17%	0%	0.1%
Impact of REPI on future projects	Utilities	2	4	0	1
% 1995	46% REPI Funds	54%	0%	0.1%	

eligible for the REPI, some types of projects are given priority access to the payments. For these priority technologies, the REPI is a more effective incentive because the probability of adequate annual funding is higher.

To further improve the policy, production payments should be firmed-up so that project owners are assured of a 10-year revenue stream. Alternatively, an entirely different policy could be used to promote non-profit renewable ownership. Regardless of which approach is taken, it is essential that the policy provides an incentive that can be used in load applications and bond offerings, and that can easily be integrated by non-profit decision-makers in project evaluations.

At the legislative level, at least two approaches can be used to decrease year-to-year program funding uncertainties and to firm-up the production incentive. First, a pool of capital could be created that is large enough to be pledged for current-year and future payments (e.g. a trust fund or escrow account), obviating the need for repeated, yearly appropriations. Second, a standing or open appropriation could be established, which reduces the likelihood of future funding suspension by creating a *commitment* to appropriate either a fixed or variable amount of money to a given program over several years. To promote stability in renewables policies more generally, legislatures should be alerted to the dangers that funding changes pose to developers and investors. Statutory language specifying the legislative intent to fund a program for a long period should be sought wherever possible.

3.5. *U.K. NFFO and contract length*

The United Kingdom's electricity industry was privatized and restructured in 1989. As part of the restructuring process, a program was set up to subsidize nuclear and

renewable energy. This program, called the Non-Fossil Fuel Obligation (NFFO), has promoted renewables through a competitive set-aside and auction since 1990, and provides renewable energy projects a premium energy sales price if they are successful in their bid for a contract. The NFFO requires the major distribution companies in the U.K. (the Regional Electric Companies) to purchase this renewable energy via power purchase contracts. The Regional Electric Companies are reimbursed the difference between the contract price and the average monthly power pool rate through a fossil-fuel levy on electricity, paid via customer electricity bills. Thus far, four NFFO auctions (called tranches) have been conducted. One more tranche is slated to occur before 2000.

Mitchell [56] and Elliot [57] describe the financing shortcomings of the NFFO. A major influence on the ultimate costs of the first two solicitations was a decision made by the European Commission that support under the NFFO should not extend beyond 1998, limiting the fixed-price power purchase contract length to a *maximum* of eight years. A number of winning project bids in the early 1990s were unable to obtain planning permission rapidly enough to take advantage of the contracts, and therefore were never constructed. Even more importantly, the shortened contract period increased financing costs and raised price premiums.

As noted earlier, lenders typically assess projects on a worst-case basis. If a project is likely to default or come close to default, lenders will not generally provide a loan. Therefore, lenders are frequently unwilling to provide a debt with a maturity that exceeds the fixed-price period of the PPA, especially for projects that are unlikely to be competitive absent price supports [58, 59]. With an uncertain revenue stream post-1998 and an expectation that power pool prices would not be sufficient to meet debt service coverage requirements, lenders were unwilling to provide long-term loans to renewable energy companies during the first two tranches of the NFFO. Six to eight-year debt repayment periods were common, dramatically increasing the price premium required by renewable developers. Using the cash-flow model introduced earlier, decreasing the debt repayment period from 12 years to 6 years, and holding all else constant, results in an increase in PV costs of approximately 26% (7 ¢/kWh) and wind costs of 20% (1 ¢/kWh).

The third tranche of the NFFO overcame some of the financing problems associated with NFFO1 and NFFO2. First, NFFO3 allowed contracts to begin within five years of the contract award date, which provided ample time for developers to site and construct projects. Second, contract lengths were raised to 15 years, allowing debt to be repaid over a longer period of time and partially dispelling the image of renewables as being overly expensive. Table 7 shows the dramatic bid price reductions in the various technology bands between NFFO2 and NFFO3. These reductions are largely attributable to the longer contract period, but are also a result of falling renewable energy capital and development costs [60]. The detrimental effect of short-term power purchase contracts is clearly illustrated by the NFFO. More generally, the NFFO experience suggests that policymakers should, wherever possible, design renewable energy programs as long-term commitments in order to facilitate less costly financing and increase policy effectiveness.

Table 7
Renewable energy cost reductions

Technology	NFFO2 price (¢/kWh)[a]	NFFO3 price (¢/kWh average)
Wind	18.2	7.1 (larger projects 8.7 (smaller projects)
Hydro	9.9	7.4
Landfill gas	9.1	6.3
Waste combustion	10.9	6.3
Other combustion	9.7	8.4
Sewage gas	9.7	None
Average	11.2	7.4

[a]Based on an exchange rate of $1.655 = £1.

4. Restructuring and implications for new policies

The U.S. electric industry is in the midst of significant change. Historically, the provision of electric power was viewed as a natural monopoly and electric utilities were regulated accordingly. In response to technical, economic, and political changes, however, a number of states have initiated regulatory and legislative processes to introduce retail competition to the electricity industry. Retail competition will eliminate the regulated utility as the sole end-use electric service provider, and customers will be allowed to contract directly with generators and marketers for power supply. Several U.S. states have already initiated retail competition and a number of bills have been introduced at the federal level designed to push competition nationally.

Electricity restructuring promises to fundamentally change the financing power projects in general and renewable energy projects in particular. In addition, restructuring has already resulted in the development of new policies designed to benefit renewable energy in a competitive environment. In this section, we discuss how restructuring will impact the financing of renewable energy projects, and we review some of the new policies designed to assist renewables in a restructured environment. As new renewable energy policies are devised, we believe that much can be gained by applying key lessons from past programs. As such, we apply the lessons from our review of past policies here in order to highlight critical design issues for the two most frequently considered policies in U.S. state and federal restructuring proceedings, namely the renewables portfolio standard and distribution surcharge-funded programs.

4.1. *Impact of restructuring on renewable energy finance*

The start of retail electricity competition is already changing the way in which power plants are financed and, in the process, promises to make life even more challenging for renewable energy developers.

4.1.1. *Fewer long-term contracts*

The non-utility generator industry as a whole, and the renewables industry in particular, has historically relied on project financing. Under retail competition, however, developers are unlikely to be able to depend on the 20–30 year power purchase agreements that have traditionally been the basis for project financing. Evidence from the natural gas market suggests that shorter-term contracts will be common [61]. After all, utilities will no longer have the obligation to serve a fixed set of captive customers and all suppliers will be faced with increased market risks. The current oversupply of electric capacity will further reduce incentives for long-term contracts.

Nonetheless, restructuring will not result in the complete elimination of medium- to longer-term commitments and a total reliance on spot market transactions. To insulate electricity generators and users from price variability, a variety of direct bilateral contracts and hedging arrangements (e.g. contracts for differences) between generators and marketers will become standard. Although these types of contracts can supply a measure of revenue certainty, they are unlikely to provide a secure revenue stream for the length of time typical of traditional NUG contracts. In the near term, many contracts are likely to be less than five years. As the market stabilizes, medium-term contracts of at most 15 years may develop.

4.1.2. *New financing approaches*

To attract project financing in a highly competitive and risky environment without a full set of long-term contracts, power developers will require more equity, less debt, and shorter debt terms. Merchant plant financing may become increasingly common [62]. Merchant power plants are generating facilities developed without a full set of sales contracts in place, but with good prospects for future sales. This form of development is used in nearly all other competitive industries and in countries that have already restructured their electric industries, merchant plants are starting to appear.

In some cases, banks may simply refuse to offer non-recourse financing and will instead focus on corporate, balance-sheet arrangements. Naturally, large companies will be best positioned to secure corporate financing for new projects given their financial resources and ability to absorb the risks that corporate-financed power projects entail.

4.1.3. *Implications for renewable energy developers*

A number of factors suggest that renewable energy developers may be particularly disadvantaged by the contracting and financing structures expected in a world of vigorous retail competition:

(1) Retail competition will increase market risks, resulting in correspondingly shorter investment horizons, increased equity requirements, reduced debt maturity, and larger debt and equity risk premiums. These changes will affect all new power plants but, because they are capital intensive, renewable energy technologies will be especially impacted.

(2) Renewables are often more costly than competing sources of generation. While a

lender may be willing to invest in a natural gas facility based on expected future electricity prices, developers will have a difficult time 'selling' a renewable energy project to a lender in this way unless additional mechanisms exist to help cover the above-market costs.

(3) Many renewable energy developers are not sufficiently capitalized and do not have a strong enough track record to attempt corporate financing for large projects [63]. In response to the increasing need for capital, mergers involving renewables developers are already occurring and can be expected to continue as the industry shakes-out and consolidates.

Ultimately, the effects of restructuring on renewable energy finance will depend upon the structure, organization, and operation of the deregulated power market as well as the adoption of public policies to promote renewables. While there is cause for concern, there are a number of scenarios under which an independent renewable energy developer could obtain needed capital. For example, there is evidence that some customers will be willing to voluntarily pay a premium for renewable energy via green power marketing [64–66]. If restructuring creates a viable and extensive customer-driven green power market, renewables developers may be able to sign sufficient short- to medium-term contracts with end-use customers of green power aggregators and point to enough 'green' demand that merchant plants can develop. Moreover, should significant additional policy incentives be established at the state or national level, renewables developers are again likely to be able to obtain needed capital.

During the transition period between the current and restructured industry, however, investment apprehension and uncertainty about the depth and breadth of the green power market may make finance particularly costly and difficult for small renewable energy companies. We now turn to a review of some new renewable energy support mechanisms designed to help overcome these and other handicaps and provide a bridge between the regulated and restructured industry.

4.2. *New policies in a restructured environment*

Under retail competition, many of the ratepayer-funded and utility-administered public policies used historically to support RETs in the U.S. will be inappropriate. For example, resource-specific set-asides and environmental adders applied to regulated entities (and not other market participants) will no longer be viable policy options because of competitive neutrality concerns. Nonetheless, within state and federal restructuring proceedings, new programs can and are being crafted to encourage the development of renewable energy. Along with programs to encourage green marketing, the renewables policy debate in the U.S. has centered on: (1) surcharge-funded programs, and (2) renewables portfolio standards. Many of the lessons and policy design issues discussed in Section 3 (e.g. policy stability, contract length, etc.) are pertinent to the design of these and other new renewables policies. Below, we briefly review surcharge-funded policies and renewables portfolio standards, and we discuss some of the ways in which our case-study lessons might be used to strengthen each type of policy.

4.2.1. *Surcharge-funded programs*

Electric service surcharges are a way to collect revenues from electric customers to support policies with public benefits, including renewable energy programs. These surcharges, frequently called system benefits charges (SBC), have generally been proposed as a volumetric fee, such as a cents per kilowatt-hour adder, that would be collected from all electricity users. Once collected, there are a large set of distribution possibilities for these funds [67]. In California, for example, a non-bypassable SBC is being used to fund a $540 million Renewable Resources Trust Fund, which in turn provides production incentives, customer credits, and capital cost buydowns to existing, new, and emerging renewable generators and developers. In addition to California, a number of other states have developed SBC-based programs as a component of their electricity restructuring plans, including: Illinois, Massachusetts, New York, Montana, Connecticut, and Rhode Island.

As demonstrated by the U.K. NFFO, REPI, and LUZ experiences, however, short-term commitments and the risk of policy change or elimination can compound financing difficulties, increase financing risk premiums, and reduce overall policy effectiveness. Therefore, for any SBC-funded program that promises payments to new renewable generators, a long-term and predictable payment stream is essential for reducing financing costs. Legislators and regulators should ensure, to the extent possible, that policies that promise long-term production incentives or above-market contract payments to renewables will continue to be funded throughout the payment period and that ‘out’ clauses are minimized. Production or contract payments of at least ten years should be sought for new projects.

While legislators can establish a multi-year SBC-funded program, because these charges are effectively a tax on electric service, they may be vulnerable to political attack. In many states, the SBC will only be authorized for a brief transition period (typically under 5 years). Transition-based programs with short collection periods are not ideal for long-term industry formation. Moreover, given a short collection period, it may be difficult to provide longer-term payments to generators. While a long-term distribution program could be funded with a shorter collection period, in many states there may be pressure to have the distribution period match the collection period. Nonetheless, if a long-term commitment of funds is possible, it should be attempted.

If long-term policy and funding commitments are simply not feasible, policymakers may need to consider using up-front grants rather than longer-term incentive payments. Alternatively, investment in market transformation activities (e.g. fuel source disclosure requirements, customer education of ‘green’ power options, etc.) or renewable energy infrastructure development (e.g. resource availability studies, technology research and development, etc.) may be the best use of funds. While a long-term perspective is desirable, these market-facilitation activities do not require the type of sustained commitments typically needed for generator incentives. Given the financing difficulties that renewable developers face under restructuring, policymakers might also consider funding direct forms of financing assistance, including low-interest loan and loan-guarantee programs.

4.2.2. *Renewables portfolio standards*

The renewables portfolio standard (RPS) allows regulators and/or legislators to require that a certain percentage of annual electric use in a given jurisdiction comes from renewable energy. To implement an RPS, a renewables purchase requirement (as a percent of total electricity sales) could be imposed upon retain electric suppliers. To add flexibility in meeting the purchase requirement, individual obligations could be made tradeable through a system of renewable energy credits (RECs) [68]. These RECs would be created when a renewable facility generates a kilowatt-hour of electricity, and the REC and renewables power sales markets are therefore partially separated. The RPSs would require, as a condition for doing business, that each retail electric supplier obtain RECs equivalent to some defined percentage of its total annual electricity sales. It is expected that the market price of RECs will represent the above-market costs of renewable energy. States that have proposed or enacted some form of an RPS include: Arizona, Maine, Massachusetts, Connecticut, and Nevada.

Under an RPS, renewable energy project owners would have revenue streams from two 'commodity' markets: the power market and the REC market. Lenders may look to both revenue sources for debt repayment. However, the stability and duration of the RPS will affect the ability of the REC market to provide the lender with sufficient revenue certainty. To minimize risk, a renewable power developer would likely seek a long-term REC sales contract with an REC purchaser (e.g. a retail electric supplier). REC purchasers, on the other hand, will only enter into long-term contracts if policy stability is assured. If legislative and regulatory commitments to the REC system are weak, retail suppliers will have little incentive to make long-term REC purchases. Why commit to buying RECs via a 10-year contract if there is some chance that the RPS will be terminated before the REC contract expires (therefore locking the buyer into purchasing RECs with no value)? Therefore, if the RPS standard and its duration are uncertain, it seems likely that RECs will be sold primarily in short-term markets. The resulting uncertainty in the REC-derived revenue stream for the renewable investor will increase the financing costs of new renewables projects by forcing developers to decrease debt leverage and reduce debt term. Our analysis suggests that overall renewables costs could increase by up to 25–50% in an unstable REC market compared to the probable cost under a stable one [69].

As with SBC-based programs, the RPS should therefore be designed as a long-term, stable commitment. There can, of course, also be costs associated with long-term commitments, and full policy certainty may not be possible or desirable from a public policy perspective [70]. Policymakers should clearly seek to remove as much of the potential for sudden or capricious changes as possible, however, and weak policy commitments and short policy durations should be avoided.

5. Conclusion

Though electricity restructuring threatens some forms of existing support for renewables, it has also brought renewed attention to renewable energy markets and policies.

Developing effective mechanisms to support new technologies is difficult, however, and policies often do not perform as well as predicted or expected. Though financing is only one of many issues that must be considered when designing and implementing support programs, the policy case studies described here demonstrate that financing is a particularly critical variable in policy design.

In addition to the impacts of tax credit policies on tax appetite and project capital structure, this paper has identified a number of uncertainties that can hamper the effectiveness of renewable energy policies, including: (1) uncertainty in the eligibility of specific renewables projects to obtain program support ; (2) a lack of assurance that the policy will be maintained and will still exist when a project comes on-line; and (3) uncertainty in the ability of the program funding mechanisms to provide a long-term, predictable revenue stream. We find that renewable energy policies should be designed with consideration given to the realities of power plant financing in order to minimize these uncertainties. Policies that do not provide long-term stability or that have other negative secondary impacts on investment decisions will increase financing costs and may reduce policy effectiveness. Long-term and predictable policy commitments can, on the other hand, lead to a decrease in financing costs, which should result in reductions in renewable energy costs and in more effective policies. In the long-run, such commitments will also help create a regulatory, political, and business climate that is conducive to continued and sustained development of the renewable energy industries.

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